Eurogas

Eurogas Corporation

2003 ANNUAL REPORT

Contents

The annual and special meeting of Eurogas Corporation will be held at 2:30 p.m. (Calgary time) on April 30, 2004 in the Viking Room of the Calgary Petroleum Club, 319-5th Avenue S.W., Calgary, Alberta, Canada. Shareholders are encouraged to attend. Those unable to attend should complete and return the form of proxy.

Abbreviations

bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boed	barrels of oil equivalent per day
GJ	gigajoules
LNG	liquefied natural gas
mcf	thousand cubic feet
mcfd	thousand cubic feet per day
mstb	thousand stock tank barrels
mmcf	million cubic feet
NGL	natural gas liquids
tcf	trillion cubic feet

Corporate Profile

Eurogas Corporation is a Calgary, Canada-based independent oil and natural gas exploration company focused on creating long-term value through the development of high-impact energy projects internationally. Eurogas is laying the groundwork for development of the proposed US$300 million Castor underground natural gas storage facility in Spain, Europe's fastest-growing natural gas market. Concurrently, Eurogas, in conjunction with experienced partners, is conducting exploration programs for oil and natural gas reserves on exploration concessions on and offshore Tunisia. The Company's activities have to date been financially supported by internally-generated cash flow from its conventional oil and natural gas production in Western Canada. Throughout 2003 Eurogas continued to maintain a strong balance sheet, with no new debt or equity issuances during the year.

In August of 2003 Eurogas' management and the Board of Directors proposed a Plan of Arrangement to divide operations into two separately incorporated and traded entities. A newly formed company, Great Plains Exploration Inc., would receive assets of, and assume responsibility for the current Canadian operations; Eurogas shareholders would receive shares in the new company. This non-taxable "butterfly" arrangement will be voted on by shareholders at the annual and special meeting on April 30, 2004.

The Company enjoys the strong support of its majority stockholder, Dundee Bancorp Inc., a Toronto-based merchant bank.

Eurogas is a publicly traded company listed on the Toronto Stock Exchange under the trading symbol EUG. At December 31, 2003 there were 75,932,181 shares issued and outstanding.

Selected Highlights

	2003	2002
Average daily production (boed)	**767**	811
Oil and gas sales, net of royalties ($ millions)	**8.78**	6.73
Cash flow from operations ($ millions)	**5.45**	3.5
Per share (diluted) ($)	**0.07**	0.05
Net earnings ($ millions)	**0.6**	4.7
Per share (diluted) ($)	**0.01**	0.06
Capital expenditures ($ millions)	**9.9**	6.3
Working capital ($ millions)	**8.8**	11.0
Common shares outstanding at December 31	**75,932,181**	75,682,181

A landmark event for Eurogas in 2003 was a decision by the Board of Directors to divide the Company into two separate operating companies. This decision was driven by the rapid advance in 2003 of the Castor Underground Natural Gas Storage project in Spain, and recognition of an opportunity to utilize Eurogas' Canadian assets as a base from which to grow a new independent Canadian oil and gas company named Great Plains Exploration Inc. The proposed corporate reorganization is also aimed at realizing the real value of Eurogas' assets by creating two "pure play" companies enabling capital markets to more readily evaluate the assets and activities of the individual companies.

Spain

Both externally and internally events are rapidly unfolding in favour of development of the Company's Castor Underground Natural Gas Storage project in Spain. Externally there is growing recognition of Castor's unique attributes, a rapid expansion of Spain's natural gas market and a growing need for security of uninterrupted energy supply. There is also continued deregulation in the energy sector and the planned Medgaz pipeline from Algeria. These factors are intensifying the need for a strategic, high deliverability, natural gas storage facility to service Spain's highly industrialized east coast. The technical attributes and history of the Castor project are explained more fully in the Review of Operations section of this report.

Internally, Castor made good progress during 2003. A state-of-the-art reservoir simulation study, commissioned with Gilbert Laustsen Jung Associates Ltd. in 2002, was completed. The study confirmed all of Eurogas' engineering assumptions concerning the suitability of the abandoned Amposta oil reservoir for conversion to a large volume, high deliverability, natural gas storage facility. A welcome unforeseen finding of the study was the conclusion that up to 15 million barrels of recoverable oil may be commercially produced prior to the start of gas injection operations prompting management to fast-track plans for drilling the first Castor well.

The Castor project has been officially accepted as a strategic element in Spain's energy transportation infrastructure, and as such, its business will be regulated in accordance with legislation and system requirements. Once in operation, its financial returns are guaranteed, irrespective of the level of facility utilization. Financial returns are based in general upon utility business models, and contain two main elements: an indexed recovery of capital investment over a twenty-year period, and, an annual

return on capital employed. An important feature of the applicable economic regime is the long-term duration of the cash flows – it is expected that 50 percent of the initial financial returns will continue to be received by Castor for many years after the original capital investment has been recovered.

The Eurogas management team has always been optimistic about Castor's chances of success. The events of 2003 have heightened the certainty that Castor is the only viable natural gas storage project able to serve east Spain and will be developed. The first well in the project, planned for drilling in the fourth quarter of 2004, is designed to evaluate the potential of evacuating commercial quantities of oil remaining in the Amposta structure and to provide data required to confirm our technical assumptions. Our goal is to have Castor in service in 2008 to coincide with the completion of the Medgaz Consortium pipeline from Algeria to Spain. Management is confident of the project's ability to attract financing given its technical strength, strategic location and security of cash flows.

Tunisia

Significant progress was made on our exploration program in Tunisia. The evolution of our Triassic TAGI sands play concept led Eurogas and its operating partner to focus on the 1.2-million-acre El Hamra block, situated in the northern portion of the Berkine Basin. In 2003, geological and seismic work resulted in the identification of two prospects and six leads on the El Hamra permit. The partners intend to drill the two prospects prior to year-end or early 2005. Eurogas is weighing its capital requirements for 2004 and may elect to farm out a portion of its 50 percent working-interest in the El Hamra block.

Meanwhile, Eurogas has gained an interest in a very exciting new permit in shallow waters off Gabes in southern Tunisia. In 2003, Eurogas and a partner were granted the Sfax seismic exploration permit which covers 1 million acres. Eurogas has a 45 percent interest in the permit. The Sfax permit is surrounded by major producing pools and was itself, in the past, the scene of two significant undeveloped oil discoveries made during the low oil price era of the 1980's. Eurogas and its operating partner are now reinterpreting existing seismic and plan to conduct a major 3-D seismic program in 2004 to optimally position wells required to test the productivity of the undeveloped oil discoveries.

Canada

Exploration and development of conventional oil and natural gas reserves in the Western Canada Sedimentary Basin continue to offer exciting growth opportunities for independent oil and natural gas producers. Eurogas has successfully maintained a solid Western Canadian oil and gas production base which has generated sufficient cash flow to fund all of the Company's growth activities in Spain, Tunisia and Canada. This strategy of employing internally-generated cash flow from domestic operations to fund its projects abroad was very successful, enabling management to maintain a strong balance sheet while providing shareholders with maximum exposure to high impact projects on a non-dilutive basis.

Re-organizing the Assets

In light of rapid advances in 2003 of the Castor natural gas storage project in Spain and the increasing demand on the Company's human and financial resources, management and Directors re-examined the Company's growth strategy and decided the time was right to separate international and domestic properties and operations into two distinct companies. Reorganizing the majority of the Canadian properties in a stand-alone company, dedicated to growth in Canada, will allow the new company to vigorously pursue significant growth opportunities available in Canada while Eurogas focuses on development of its Spanish and Tunisian properties. With approval of shareholders at the April 30, 2004 meeting, a new Canadian company named Great Plains Exploration Inc. will be launched under the direction of a new management team and Board of Directors.

Outlook

The year ahead promises to be an exciting one for Eurogas. In Spain, the drilling of the first well for the Castor storage project marks an important milestone toward the full development of what is quickly being recognized as Spain's premier underground natural gas storage facility.

In Tunisia, Eurogas is participating in an important 3-D seismic program on the Sfax permit in the Gulf of Gabes. The program is designed to determine the prime location for wells to exploit the undeveloped oil reserves on the permit, while on our El Hamra permit two major prospects have been readied for drilling.

Separating Canadian assets and operations and the foreign assets and operations into two public corporations will allow each company to focus its resources on specific projects. Eurogas will advance its underground natural gas storage project in Spain and exploration in Tunisia; Great Plains Exploration will focus on exploration and development in Western Canada.

In Canada, a new independent oil and gas company directly owned by Eurogas shareholders and under the management of a dynamic new management team and Board of Directors will be launched. The new company will come into being having a solid asset base heavily weighted to natural gas.

Once again, the past year's successes would not have been possible without the tremendous enthusiasm and dedication of Eurogas' staff and associates in Calgary, Spain and Tunisia, a dedicated team that has so successfully managed and advanced the diverse assets and undertakings of the Company. My deepest appreciation goes to each of you. Eurogas' major shareholder, Dundee Bancorp Inc., is also owed thanks for its continued support, as are all of Eurogas' individual shareholders for their patience with the development of our long-term projects. I thank my fellow Directors for their continued guidance and counsel.

This report is dedicated to the memory of Lord William Shaughnessy who passed away in London, England on May 22, 2003. Lord Shaughnessy served diligently as a Director of the Company since its inception in 1995. Eurogas mourns his loss.

On Behalf of the Board of Directors,

Julio Poscente
Chairman of the Board and Chief Executive Officer
March 19, 2004

SPAIN: THE CASTOR UNDERGROUND NATURAL GAS STORAGE PROJECT

> Castor has all the required attributes and is the best candidate to meet the urgent needs of Spain's growing natural gas market.

> Over the longer term, Castor will play a major role in the development of both regulated and unregulated natural gas markets in southern Europe.

> 2004 activities include completion of an environmental impact study, the drilling of the initial well and completion of a Design Basis Memorandum for on and offshore facilities.

SIGNIFICANT EVENTS IN 2003

Progress accelerated in 2003 on Eurogas' Castor Underground Natural Gas Storage Project. In late 2003 Eurogas obtained high-quality 3-D dimensional seismic data from Shell International, the field's original operator. The data are being re-processed for interpretation using advanced seismic processing technology. The results will be used to select drilling locations and to design horizontal trajectories for the gas injection/withdrawal wells.

Most important, Gilbert Laustsen Jung Associates Ltd., a highly respected Calgary-based engineering firm, completed a reservoir simulation study which confirmed all of Eurogas' key engineering assumptions concerning the suitability of the reservoir for the storage of natural gas.

The GLJ report also concluded that attic areas in the Amposta reservoir may hold up to 15 million barrels of recoverable oil and reservoir performance will improve during gas withdrawal cycles if remaining oil is evacuated prior to gas injection operations. The field was producing at a restricted rate of 2,000 barrels of oil per day through two wells when decommissioned in 1988, a time of very low oil prices. It is Eurogas' intention to evacuate remaining oil volumes at the earliest practical date. If successful, this could provide significant cash flow early in the project life. Eurogas opened an office in Madrid to coordinate its expanding operations in Spain and to prepare for the drilling of the first Castor well scheduled for the fall of 2004.

CASTOR QUICK FACTS: PROJECT DESIGN

1 **Ownership**
Eurogas Corporation owns a 71 percent interest in Castor UGS Limited Partnership and is the general partner and operator.

2 **Storage Reservoir**
The abandoned "Amposta" Jurassic carbonate reservoir has a strong natural water drive. It is located in 60 metres of water 20 kilometres offshore Spain's east coast.

3 **Operating Design**
The project envisions nine horizontal injection/withdrawal wells, and an offshore platform, connected by a seabed pipeline to onshore treatment and compression facilities. The pipeline will be tied in to existing and planned Medgaz natural gas trunk pipeline.

4 **Working Storage Capacity and Deliverability**
1 billion cubic metres of working gas (35 bcf), plus 600 million cubic metres (21 bcf) of cushion gas. The project would deliver 25 million cubic metres of gas per day (more than 800 mmcf) at a constant rate from 0-100 percent of rated storage capacity.

CASTOR: MEETING SPAIN'S STORAGE NEEDS

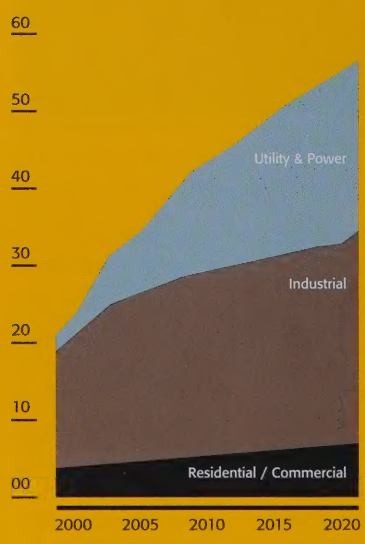
Entering 2004, Eurogas is confident that Castor has all of the required attributes for gas storage and is the best candidate to meet the urgent needs of the growing and increasingly deregulated natural gas market in Spain. As in other natural gas markets, storage serves to reduce price volatility and ensure reliability of service during periods of high demand or supply disruption. In Spain, this need will become acute upon completion of the planned Medgaz Consortium gas pipeline from Algeria, along Spain's Mediterranean coast into southern France.

In Eurogas' view, Castor is the crucial element needed to satisfy Spain's legal requirements for storage capacity equivalent to 35 days' average natural gas consumption. To date there are no other known candidates for storage facilities of volume, deliverability, quality or location comparable to Castor.

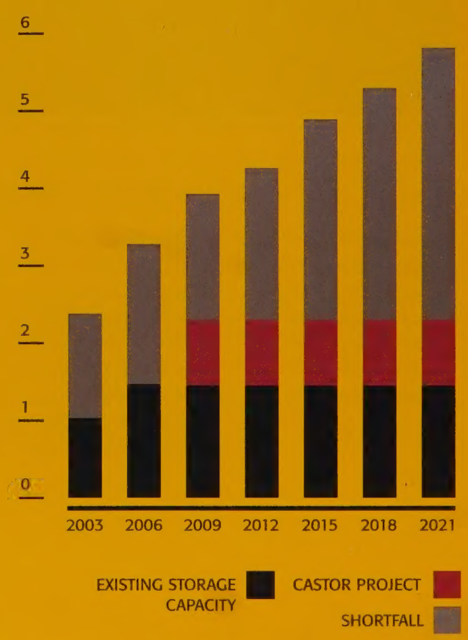
Over the longer term, continued liberalization of natural gas markets in Spain and throughout Europe, coupled with further growth in natural gas demand, suggest that Castor will play a major role in the development of both regulated and unregulated natural gas markets in southern Europe. Castor can be expanded materially from its Phase I delivery rate of 25 million cubic metres per day. There is potential for future development as a regional hub for natural gas peak demand to ensure reliability of supply for end-users while providing capacity for forward activities such as trading and hedging on a fee-for-service basis.

An increase in the number of wells from 8 to 16 would increase daily deliverability up to 50 million cubic metres per day and 3 billion cubic metres, respectively.

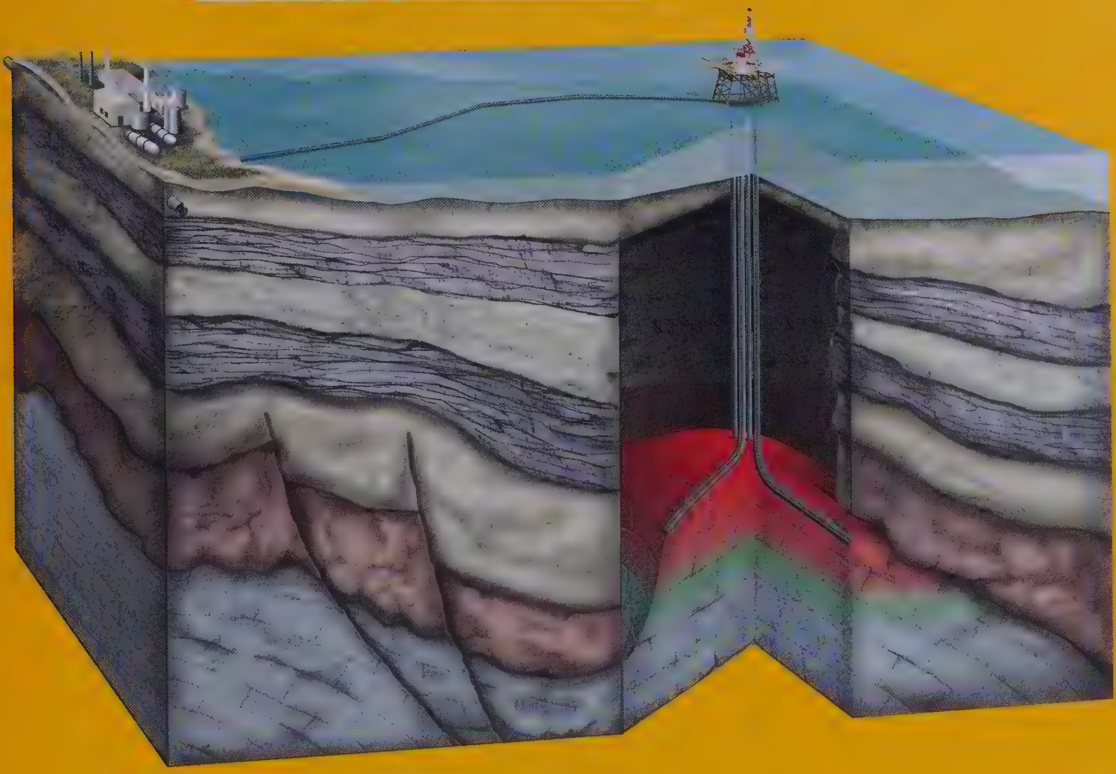
Projected Annual Natural Gas Demand: Spain 2000-2020 (Billions of Cubic Metres)



35-Day Gas Storage Requirements - SPAIN (Billions of Cubic Metres)



CASTOR is strategically located to serve the highly industrialized East coast of Spain.



COMMISSIONING AND OPERATION

5 **Percentage of 2008 Spanish Storage Capacity**
30 percent of Spain's needs.

Oil Recovery
Potential for recovery of up to 15 million barrels of oil.

6 **Estimated Cost to Commissioning**
US$300 million.

7 **Forecast Completion and Commissioning**
2008, contingent on regulatory approvals.

8 **Nature of Operation**
Utility project earning regulated rate of return, with government guarantees for costs; part of the transportation function in Spain's liberalized natural gas industry, and an element of Spain's "national energy infrastructure" program. Facilities operated by Systems Operator.

CASTOR: 2004 PROGRAM

Given all of the positive results to date, Eurogas' principal task in 2004 is to drill the first development well in the Amposta reservoir. The well will be located and designed for gas injection/withdrawal service and may be used initially to evacuate crude oil prior to natural gas storage. Planned for Q4, the drilling project marks the initial step toward the start of development of the Castor Project. In early 2004 Eurogas launched an environmental impact study required before drilling and we anticipate timely approval for the drilling program from the regulatory authorities.

WORK COMPLETED

1995–1997	1998	1999	1999–2001	2002–2003
> Eurogas recognizes opportunity for Castor gas storage project > Eurogas obtains research licence > Eurogas conducts initial analysis and study	> Eurogas conducts reservoir evaluation and offshore pipeline survey > Major additions to gas storage needed as Spain's new Hydrocarbons Sector Law mandates storage capacity equivalent to 35 days' average natural gas consumption	> Eurogas conducts geo-technical survey, project technical study, basic engineering study and environmental impact study	> Eurogas presents Castor project proposal to Spanish Energy Commission > Spanish government recognizes Castor as element of national energy infrastructure > Eurogas increases interest in Castor UGS Limited Partnership to 71 percent > Eurogas commissions independent reservoir simulation study	> Independent reservoir certification and simulation confirms suitability of reservoir for use as storage facility > Simulation supports evacuation of oil prior to gas storage activity – up to 15 million barrels of oil recoverable > Eurogas begins re-processing and interpretation of 3-D seismic data for placement of wells

The Castor 1 well is a continuation of Eurogas' technical due diligence required to confirm assumptions derived from engineering, geological study and 3-D seismic interpretation, such as reservoir stratigraphy, pressures, cap rock seal and reservoir fluid types.

Other activities planned for 2004 include the commencement of a Project Environmental Study and a Design Basis Memorandum (DBM). The DBM is a precursor to the Front End Engineering and Design (FEED) study and will take five months to evaluate major engineering processes and materials. In early 2005 Eurogas will file an application to convert the Castor exploration permit to an exploitation concession.

WORK AHEAD

2004	2005	2006-2007	2008
> Complete environmental impact study for drilling > Drill well into Amposta reservoir > Begin project environmental study for 2005 Development Application > Complete DBM as a precursor to 2005 FEED study > Assemble project team to begin preparation of the regulatory process > Open project financing discussions	> Prepare and submit Development Application > Determine financial structure > Obtain project financing > Commence FEED Study	> Commence oil production > Drill 8 development wells > Construction of on and offshore facilities and pipelines	> Complete construction > Inject cushion gas > Bring Castor underground natural gas storage project into service > Commence commercial storage operations concurrent with commissioning of planned Medgaz Consortium natural gas pipeline

TUNISIA EXPLORATION

2003 ACTIVITIES

Following abandonment of the unsuccessful Jorf 1 exploration well in March 2003, Eurogas has focused its exploration efforts on the 1.23-million acre El Hamra permit, located 100 kilometres south of the Bazma and Jorf permits in south Tunisia. In early 2003, Eurogas and its operating partner completed a surface geology study and finalized the seismic processing and interpretation for the El Hamra permit. The completion of this technical work at El Hamra generated two exploration prospects for drilling and six leads that will require additional seismic definition. Engineering work commenced in late 2003 to prepare the two prospects delineated for drilling during the latter half of 2004.

In December 2003, Eurogas acquired a seismic option and prospecting permit for the Sfax Offshore Block in the Gulf of Gabes of eastern Tunisia. This shallow water permit covers 908,000 gross acres (3,676 square kilometres). Eurogas holds a 45 percent working interest in the permit, which is operated by Gaither Petroleum Corporation, an experienced independent exploration and production company based in Houston, Texas. The permit carries a minimum work commitment requiring the reprocessing of 1,000 kilometres of existing seismic and acquiring a new 100 square kilometre 3-D dimensional seismic program during the permit's two-year term.

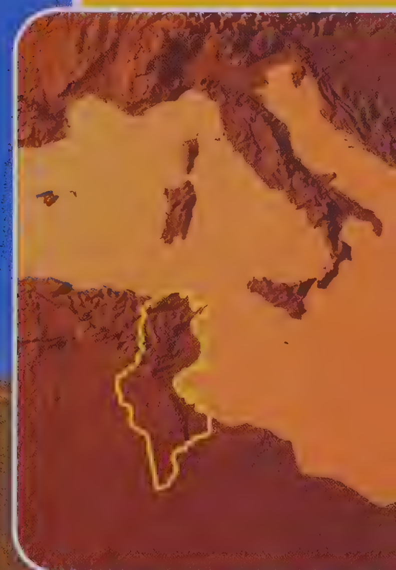
EVOLUTION OF THE TRIASSIC TAGI SANDS PLAY

Eurogas' high-impact exploration program in Tunisia is a long-term program seeking to prove the north-eastward extension of the Triassic TAGI sands fairway out of Algeria. Since 1993, in excess of 5 billion barrels of recoverable oil has been found in the TAGI sands in the Berkine Basin of eastern Algeria. The Company's geological studies, geochemical analysis, seismic interpretation and the drilling of two wells on the Jorf and Bazma permits have confirmed the physical extension of the Triassic TAGI sands, which exhibit excellent reservoir quality and areal extent, plus demonstrated the migration of hydrocarbons. Although our program has confirmed the accuracy with which we have been able to identify thick, high quality reservoir sands, we failed to find commercial quantities of oil and gas. Extensive analysis indicate that the prospective TAGI pool sizes tend to be small in the central region of Tunisia. Economic evaluations, using risk analysis, do not support continued exploration for limited pool sizes with their lower economic return. Consequently, in late 2003, Eurogas decided to shift the focus of its exploration activities to the El Hamra permit in southern Tunisia in search of larger prospects. This region is the scene of active drilling, which has resulted in three major Ordovician discoveries by other operators in 2003.

Eurogas and its partner have intensified their exploration program for the Triassic TAGI sands on the El Hamra permit, which is located 100 kilometres to the south of Bazma-Jorf in an area understood to be the northern extension of the Algerian Basin.

2004 PROGRAM

Eurogas will participate in a two well drilling program on the El Hamra project and a 3-D seismic program on the Sfax permit active programs at both Tunisia plays throughout 2004.



TUNISIA QUICK FACTS

1 Eurogas has been active in Tunisia since 1992 and has pioneered the Triassic TAGI sands play concept. Following interpretative seismic work in 2003, the Company identified two prospects: El Hamra East and El Hamra South.

2 The two Triassic exploration wells on the El Hamra permit are planned to be drilled before year-end 2004 and could access significant oil reserves.

3 The Sfax permit, located in shallow water off Tunisia's east coast, was awarded to Eurogas in 2003. Significant discoveries in the 1980's drill-stem-tested at 600 and 1,200 barrels of oil per day before being abandoned due to low oil prices.

EL HAMRA PERMIT

Extensive interpretative seismic work during 2003 resulted in the identification of two drillable locations. The El Hamra East prospect lies in the south-eastern corner of the permit and is the larger with 56 square kilometres of areal closure, which could contain upwards of 850 million barrels of oil-in-place. Existing gas and oil pipelines cross over the eastern nose of the prospect and are within 2.5 kilometres distance of the proposed EH-1 wellsite location. Due to the well's close proximity to pipelines and roads, the EH-1 location will likely be drilled first.

The El Hamra South prospect lies 36 kilometres west of the EH-1 location in an area of low sand dunes. Seismic mapping indicates a possible 32 square kilometres area of structural closure, which is split into three lobes. The north lobe, with the best seismic definition, will be drilled by the EH-2 well. The three combined lobes could contain 485 million barrels of oil reserves. Both wells will bottom in the underlying Ordovician sandstones, which have proven to be prospective south of the El Hamra permit. Potential reserves in the Ordovician are expected to be gas and condensate, which makes the Ordovician a good secondary target for exploration on the permit. Eurogas will participate in these two Triassic exploration wells planned for drilling before year-end 2004. Total combined costs are budgeted at US$6 million. Eurogas plans to seek farm-out partners to fund its 50 percent working-interest share.

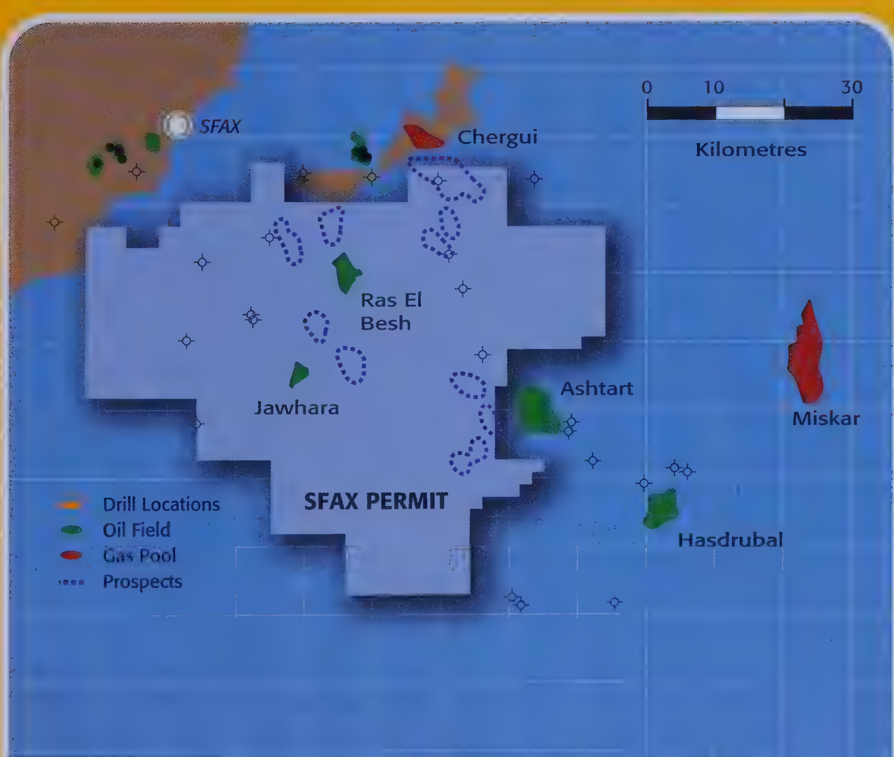
SFAX PERMIT

Eurogas is pursuing Tunisia's shallow offshore on the Sfax permit, which is focused on proving the commercial viability of Eocene and Late Cretaceous oil pools that were discovered by major operators during the low oil price era of the 1980's, deemed uneconomic and were subsequently abandoned.

The Sfax permit is located in the highly prospective Pelagian Basin, adjacent to the producing Ashtart field with 320 million barrels of recoverable reserves. Both Sfax and Ashtart are on the same productive trend as the Hasdrubal field and other large, producing pools that extend into Libyan waters. The two significant discoveries made on the Sfax permit drill-stem-tested at 600 and 1,200 barrels per day, respectively, before being abandoned.

Eurogas and its partner intend to re-drill these previous discoveries in conjunction with developing new plays identified by seismic and well control. To evaluate the identified structures, the partnership will conduct a 280 square kilometre 3-D seismic program over the prospective regions in 2004. In addition, Eurogas plans to reprocess 1,000 kilometres of existing 2-D seismic lines in an area where existing seismic has identified several structural leads which remain unexplored. Capital expenditures in 2004 are budgeted at US$3 million.

This area's demonstrable prospectivity, combined with the excellent exploration techniques currently available, including advanced 3-D seismic re-processing, horizontal drilling and new floating production systems, leave Eurogas optimistic about the possibility of a commercial discovery at Sfax.



WESTERN CANADA

Production for 2003 consisted of 2.9 mmcf per day of natural gas and 280 barrels per day of crude oil and liquids, for a total of 767 boe per day. This was essentially unchanged from year-end 2002. Eurogas' natural gas weighting increased to 80 percent at year-end 2003 from 60 percent at year-end 2002.

The Company's Western Canada properties continued to fulfill their primary role of furnishing low-risk cash flow to help fund the international projects. In September and November, respectively, Eurogas disposed of non-core interests in Saskatchewan at Cantuar and Ingoldsby, both fully exploited properties with little upside potential. The sale generated proceeds of $3.6 million, net of adjustments, funding most of the Company's $5.5 million 2003 capital program. The remaining $1.9 million was funded by internal cash flow.

Eurogas' 2003 capital program in Canada included participation in the drilling of 30 wells at Pembina-Rat Creek and Hamilton Lake of central Alberta, and Hatton in southwest Saskatchewan. The success rate was 97 percent, with only one suspended hole. Eurogas operated five 100 percent working-interest wells under its ongoing Belly River shallow gas program at Hamilton Lake, four of which were successful. In addition, two of four natural gas wells drilled at Pembina-Rat Creek in 2002 were tied in and brought on-production in June 2003. The remaining two wells will be tied in to facilities after additional wells are drilled in the area.

The Canadian capital program of $4.9 million was directed at exploration and development activities yielding net incremental production of 2 mmcf per day of natural gas. New proved plus probable reserves added through the drill bit replaced 96 percent of reserves produced during 2003 at an onstream cost of $14,715 per boe per day.

The Company's average sales price during 2003 was $6.64 per mcf for natural gas and $36.36 per barrel for crude oil and liquids. Operating costs averaged $7.21 per boe and royalties averaged $7.20 per boe, yielding an average netback of $24.17 per boe. Total revenues were $11.5 million for the year. These results generated cash flow from operations of $5.5 million.

Operating Summary

	Three Months ended December 31		Twelve Months ended December 31	
	2003	2002	**2003**	2002
Oil and gas sales, net of royalties	**$ 2,156,830**	$ 2,054,356	**$ 8,779,110**	$ 6,730,095
Natural gas marketing revenue	**–**	1,415,002	**2,580,771**	1,479,727
Interest and other	**38,983**	23,414	**157,719**	154,601
	$ 2,195,813	$ 3,492,772	**$ 11,517,600**	$ 8,364,423
Oil and NGL production – bbls	**17,782**	29,379	**102,217**	122,997
Gas production – mmcf	**317**	250	**1,065**	1,037
Average oil and NGL price per bbl	**$ 35.85**	$ 36.36	**$ 36.36**	$ 32.15
Average gas price per mcf	**$ 5.87**	$ 5.66	**$ 6.64**	$ 4.17
Production – boed	**768**	773	**767**	811
Oil and gas revenue per boe	**$ 35.34**	$ 33.18	**$ 38.58**	$ 27.96
Royalties, net of ARTC	**$ 341,137**	$ 306,135	**$ 2,014,726**	$ 1,546,165
percent of revenue	**13.7%**	13.0%	**18.7%**	18.7%
Operating costs	**$ 436,213**	$ 573,368	**$ 2,017,629**	$ 2,036,968
Per boe	**$ 6.17**	$ 8.06	**$ 7.21**	$ 6.89
Netback per boe	**$ 24.34**	$ 20.86	**$ 24.17**	$ 15.85
G&A expense	**$ 236,031**	$ 256,854	**$ 1,464,135**	$ 1,366,743
Per boe	**$ 3.34**	$ 3.61	**$ 5.23**	$ 4.62
Depletion, depreciation and site restoration	**$ 835,909**	$ 566,000	**$ 2,234,094**	$ 1,893,000
Cash flow from operations	**$ 1,498,232**	$ 1,307,575	**$ 5,456,311**	$ 3,498,305
Per boe	**$ 21.20**	$ 18.39	**$ 19.50**	$ 11.82
Per share – diluted	**$ 0.02**	$ 0.02	**$ 0.07**	$ 0.05
Earnings before taxes, unrealized exchange loss and other items	**$ 684,417**	$ 777,095	**$ 3,333,971**	$ 1,710,071
Net earnings	**$ 30,294**	$ 4,444,391	**$ 572,570**	$ 4,720,121
Per share – diluted	**$ –**	$ 0.06	**$ 0.01**	$ 0.06
Capital investment				
Canada				
Land	**$ 68,589**	$ 124,143	**$ 963,391**	$ 214,819
Drilling, Completion and equipping	**1,145,810**	630,471	**3,944,035**	1,103,516
Other	**93,895**	115,713	**601,365**	576,882
	1,308,294	870,327	**5,508,791**	1,895,217
Tunisia	**926,353**	284,771	**2,372,956**	2,965,787
Spain	**697,092**	211,041	**1,994,048**	1,399,650
Total capital expenditures	**$ 2,931,739**	$ 1,366,139	**$ 9,875,795**	$ 6,260,654
Working capital	**$ 8,831,564**	$ 11,045,819	**$ 8,831,564**	$ 11,045,819
Common shares outstanding at December 31			**75,932,181**	75,682,181

This discussion and analysis of financial condition and results of operations for the year ended December 31, 2003 should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2003 and 2002, together with the notes related thereto.

Eurogas Corporation is a Canadian-based oil and natural gas company whose common shares are traded on the Toronto Stock Exchange (TSX). In 2003 Eurogas carried on exploration, development, production and/or acquisition activities in Canada, Spain and Tunisia.

The Board of Directors has proposed a plan to reorganize the Company by the separation of the Canadian assets and operations and the foreign assets and operations into two separate public companies. The reorganization is subject to the approval of the shareholders of the Company and relevant regulatory bodies. The Board of Directors and management of the Company believe that the proposed corporate reorganization will serve to enhance shareholder value by having management focus on realizing the full value of the Company's unique projects in Tunisia and Spain. A separate management team and Board of Directors will focus their efforts on growing the assets of the new corporation in Canada while another management team and Board of Directors will dedicate their time and talents to growing the international assets of Eurogas Corporation. The name of the proposed new Canadian company will be Great Plains Exploration Inc. and the new management and Board of Directors will be announced at the Eurogas Annual General Meeting on April 30, 2004. A detailed discussion of the assets and business strategies of the two public companies is included within this Annual Report.

FORWARD-LOOKING STATEMENTS

This Management's Discussion and Analysis may contain forward-looking statements including expectations of future capital programs and commodity prices. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to, operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures, and commodity price and exchange rate fluctuation and uncertainties.

2003 HIGHLIGHTS

> Earnings before taxes were $1.7 million in 2003, after the deduction for unrealized exchange losses of $1.4 million and commissions of $0.2 million on a prior year's sale of Yamalo. In 2002, earnings before taxes were $6.4 million, after the inclusion of a $4.7 million gain on the recovery of amounts previously written off relating to Yamalo.

> In Spain, Eurogas has completed a series of engineering and geo-technical studies to confirm the suitability of the abandoned Amposta oil reservoir for conversion to underground natural gas storage. This project, named Castor, will be capable of serving the needs for the growing natural gas infrastructure on Spain's highly industrialized east coast. Plans to drill a well in Q4 2004 are underway. The purpose of the well is to acquire technical data required to confirm the suitability of the Amposta structure for gas storage and that commercial oil production is feasible.

> Eurogas, together with a joint-venture partner, was awarded the 908,000-acre Sfax permit located offshore in Tunisia's Gulf of Gabes. The joint-venture partners plan to reprocess existing seismic data, acquire a minimum of 150 square kilometres of new 3-D seismic in order to define two previously drilled structures which tested 1,200 barrels per day and 600 barrels per day of oil, respectively, and proceed to drilling programs in subsequent years aimed at developing the oil reserves.

> Eurogas participated in the drilling of a well on its 20 percent interest Jorf permit in Tunisia. The well failed to find significant hydrocarbons, and was abandoned. The Company subsequently relinquished its interest in the Jorf permit.

> Eurogas participated in the drilling of 30 (15.3 net) wells in Canada in 2003, primarily targeting natural gas plays. Of the 30 wells, 29 were completed as gas wells. On a proved plus probable basis, reserve additions replaced 96 percent of the current year's production.

> The Company sold its interests in oil and gas properties in Saskatchewan for $3.6 million, net of adjustments.

> The strengthening Canadian dollar in relation to the U.S. dollar resulted in an unrealized foreign exchange loss in 2003 of $1.4 million in respect of the Company's U.S.-denominated short-term cash deposits. Mitigating these unrealized losses is the fact that the majority of future costs incurred in Tunisia and Spain will be made in U.S. dollars.

OIL AND GAS SALES

($000s)	**2003**	2002	% change
Gross oil and natural gas liquid sales	**3,717**	3,952	(6)
Gross natural gas sales	**7,077**	4,324	64
Royalties	**(2,308)**	(1,703)	36
ARTC	**293**	157	87
Oil and gas sales, net of royalties	**8,779**	6,730	30

Oil and gas sales, net of royalties, increased 30 percent in 2003 to $8.8 million. Production volumes on a barrel of oil equivalent basis (boe) (6:1 gas to oil) decreased from 811 boe per day in 2002 to 767 boe per day in 2003, negatively affecting sales revenue by $0.6 million, year-over-year. The production decreases were due primarily to the sale of producing properties in Saskatchewan between September and November of 2003, which were producing approximately 180 barrels per day of oil (38 bbls/d annualized). Higher commodity prices in 2003 compared to 2002 contributed $3.1 million in increased revenues, more than offsetting the impact of the production decreases. Commodity prices are expected to remain strong in 2004.

	2003	2002	% change
Oil and natural gas liquids volumes – mbbls	**102**	123	(17)
Oil and natural gas liquids price – $/bbl	**36.36**	32.15	13
Gross oil and natural gas liquids sales – $000	**3,717**	3,952	(6)
Natural gas volumes – mmcf	**1,065**	1,037	3
Natural gas price – $/mcf	**6.64**	4.17	59
Gross natural gas sales – $000	**7,077**	4,324	64

Natural gas volumes comprised 64 percent of total volumes on a boe basis in 2003, compared to 58 percent in 2002. At year-end 2003, natural gas volumes accounted for 80 percent of total volumes on a boe basis.

The following table summarizes the changes in the Company's net oil and gas sales between 2002 and 2003:

VARIANCE ANALYSIS

($000s)	
2002 oil and gas sales, net of royalties	6,730
Increase (decrease) arising from:	
Lower oil and liquids volumes	(756)
Higher oil and liquids price	518
Higher natural gas volumes	189
Higher natural gas price	2,567
Increase in royalties	(605)
Increase in ARTC	136
2003 oil and gas sales, net of royalties	**8,779**

ROYALTIES

Total royalties before the Alberta Royalty Tax Credit (ARTC) increased from $1.7 million in 2002 to $2.3 million in 2003, an increase of 36 percent. As a percentage of sales, 2003 royalties were 21.4 percent compared to 20.6 percent for 2002. The increase in royalties as a percentage of oil and gas sales is due to higher commodity prices, offset partially by the sale of properties with high Crown royalty rates. Crown royalties, as a percentage of total royalties, decreased from 79 percent in 2002 to 76 percent in 2003.

NATURAL GAS MARKETING REVENUE

One of the Company's producing properties in Saskatchewan included a reservoir that served as a natural gas storage facility. During 2002 and the first half of 2003, the Company purchased natural gas volumes and immediately entered into binding contracts to sell the natural gas to various industry producers. This buy-sell arrangement netted the Company $313,000 over the two years. During 2003, total revenues on the sale of natural gas totalled $2.6 million at an average sales price of $6.06 per mcf. The cost of natural gas sold during 2003 totalled $2.4 million at an average purchase price of $5.71 per mcf. During 2002, total revenues on the sale of natural gas totalled $1.5 million at an average sales price of $5.11 per mcf. The cost of natural gas sold during 2002 totalled $1.3 million at an average cost of $4.54 per mcf. The Company sold its interest in this property in 2003 and no further buy-sell arrangements were entered into by the Company.

OPERATING EXPENSES

Operating expenses for both 2003 and 2002 totalled $2.0 million. On a boe basis, 2003 operating costs were $7.21 per boe compared to $6.89 per boe, a 5 percent increase. Reduced production accounted for the increase on a boe basis.

GENERAL and ADMINISTRATIVE EXPENSES

($000s)	**2003**	2002	% change
Gross G&A – Canada	**1,759**	1,651	7
Recoveries	**(28)**	(23)	22
Capitalized amounts	**(267)**	(261)	2
Net G&A – Canada	**1,464**	1,367	7

Gross general and administrative expenses increased by 7 percent to $1.76 million in 2003. Included in 2003 is $0.1 million of settlement costs associated with a working-interest claim. On a boe basis, gross G&A increased by 13 percent from $5.58 in 2002 to $6.28 in 2003, and net G&A increased by 13 percent from $4.62 in 2002 to $5.23 in 2003.

Boe	2003	2002	% change
Gross G&A – Canada	**6.28**	5.58	13
Recoveries	**(0.10)**	(0.08)	25
Capitalized amounts	**(0.95)**	(0.88)	8
Net G&A – Canada	**5.23**	4.62	13

DEPLETION, DEPRECIATION AND SITE RESTORATION

	2003		2002		% change
	$000s	**$/Boe**	$000s	$/Boe	
Depletion and depreciation	**1,666**	**5.95**	1,629	5.50	2
Site restoration provision	**568**	**2.03**	264	0.89	115
Total	**2,234**	**7.98**	1,893	6.39	18

Depletion and depreciation remained relatively flat at $1.6 million in 2003. On a boe basis, depletion and depreciation increased 8 percent from $5.50 to $5.95. The increase is due to lower than expected volumes of gas reserves attributed to four new wells in the Pembina-Rat Creek area. The increase in site restoration is due to an increase in the per well estimate of costs to abandon and reclaim existing oil and natural gas sites.

OTHER ITEMS

Subsequent to abandonment of the Jorf 1 well and completion of a geo-technical study to determine the potential of other prospects on the permit, the Company relinquished its interest in the Jorf permit in Tunisia in 2003.

During 2002, the Company received additional proceeds of $4.6 million (US$3 million) in connection with the sale of all of its shares in Yamalo, a wholly-owned subsidiary which held a 50 percent interest in Urengoil, a Russian joint stock company. A provision for outstanding commissions in the amount of $200,250 (US$150,000) has been recorded in 2003, and paid subsequent to year-end.

FOREIGN EXCHANGE

The strengthening Canadian dollar in relation to the U.S. dollar during 2003 resulted in an unrealized foreign exchange loss of $1.4 million on its U.S.-denominated short-term cash deposits. The Cdn$/US$ exchange rate declined from a December 31, 2002 rate of 1.58 to a December 31, 2003 rate of 1.29. Mitigating these unrealized losses is the fact that the majority of future expenditures to be incurred in Tunisia and Spain will be in U.S. dollars.

CAPITAL AND INCOME TAXES

Capital tax expense increased from $104,766 in 2002 to $111,754 in 2003, an increase of 7 percent. Saskatchewan Capital Tax comprised 77 percent and 87 percent of the current tax expense in 2003 and 2002, respectively. The remaining capital tax expense relates to Large Corporations Tax. The Company paid no current income tax in 2003 or 2002.

The components of the recorded future income tax asset are summarized below:

($000s)	**2003**	2002	% change
Oil and gas properties	**887**	1,577	(44)
Non-capital loss carry-forwards	**–**	546	(100)
Abandonment and site restoration	**363**	185	96
Total	**1,250**	2,308	(46)

The reduction in the timing differences related to oil and gas properties and non-capital loss carry-forwards is due to the application of 2003 earnings before taxes and foreign exchange losses, and the impact of income tax reassessments. The increase in timing differences relating to abandonment and site restoration arises from the 2003 provision exceeding actual restoration expenditures in the year.

At December 31, 2003, the Company had approximately $9.6 million of tax pools available for deduction against future earnings (2002 – $12.8 million). A breakdown of the tax pool balances is as follows:

($000s)		Maximum Annual Rate of Deduction
Canadian Development Expenses	2,342	30%
Canadian Oil & Gas Property Expenses	4,245	10%
Undepreciated Capital Cost	2,733	25% average
Foreign Exploration & Development Expenses	321	10%
Total	9,641	

CAPITAL EXPENDITURES

Capital expenditures, excluding actual abandonment and site restoration costs, totalled $9.9 million in 2003 compared to $6.3 million in 2002. The change in oil and gas properties during 2003 and 2002 is summarized below:

($000s)	**2003**	2002	% change
Balance, January 1	**29,438**	24,091	22
Canadian Expenditures:			
Lease acquisitions	**963**	215	348
Geological and geophysical	**153**	293	(48)
Drilling, completion and workovers	**2,799**	577	385
Equipping and facilities	**1,146**	526	118
Capitalized amounts and other	**448**	284	58
Subtotal	**5,509**	1,895	191
Disposition of oil and gas properties	**(3,588)**	–	N/A
Net Canadian Expenditures	**1,921**	1,895	1
International Expenditures:			
Tunisia exploration costs	**2,373**	2,966	(20)
Spanish pre-development costs	**1,994**	1,400	42
Adjustment for change in interest in Partnership	**(62)**	715	(109)
Net international expenditures	**4,305**	5,081	(15)
Depletion and depreciation – Canada	**(1,666)**	(1,629)	2
Balance, December 31	**33,998**	29,438	15

Canadian Expenditures

Capital expenditures, before dispositions, relating to oil and natural gas properties were $5.5 million for 2003, an increase of 191 percent over 2002 expenditures of $1.9 million. This increase is attributable to an active drilling program at the operated Hamilton Lake property, as well as non-operated activity at Hatton, Kitto Lake and Pembina.

The Company sold its interest in two Saskatchewan oil properties, Cantuar and Ingoldsby. At the time of sale, the two properties were producing oil at an approximate rate of 180 barrels per day. Proceeds received on the sale of these two properties were $3.6 million, after adjustments. With the sale of the Company's interest in the Cantuar property in 2003, the Company eliminated its gas delivery commitments that were in place at December 31, 2002. A 2004 capital budget of $4.4 million was approved for the development of the existing asset base. Given the number of new initiatives which Great Plains management expect to bring forth in 2004 there will no doubt be modifications to the budget both terms of priorities and overall expenditure.

International Expenditures

Eurogas invested a total of $2.4 million in its projects in Tunisia in 2003, compared to $3.0 million in 2002. For 2003, the Company participated in the drilling of the Jorf 1 well, and incurred costs for technical studies on its El Hamra and Sfax permits.

The 2004 capital budget for Tunisia is US$4.9 million, which includes the drilling of two wells at El Hamra, and a 3-D seismic program on the Sfax Permit. The Company is pursuing options to identify a joint-venture partner to share in the costs of the El Hamra drilling project.

Spending on the Castor UGS project in Spain totalled $2.0 million in 2003, compared to the $1.4 million incurred in 2002. Costs in 2003 included pre-drilling and administrative costs, and reprocessing fees relating to the seismic evaluation.

The 2004 capital budget for Spain is anticipated to total US$8.0 million, including the drilling and test of an initial well.

The Company capitalizes all overhead expenses on its international projects as these projects are in the exploratory and pre-development phases.

RESERVES

Gilbert Laustsen Jung Associates Ltd. (GLJ) of Calgary, Alberta, independent petroleum consultants, have prepared a report wherein GLJ has evaluated, effective January 1, 2004, the quantity and estimated future cash flow of the Company's total estimated proved Canadian reserves.

Effective September 30, 2003, the Alberta Securities Commission adopted new regulations - National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities - to govern the way energy companies report their oil and gas reserves. NI 51-101 rules create a more stringent standard for classifying reserves as "proved" and a new "probable" category that is approximately 50 percent of reserves allowed under the old "probable" figure. Reserves evaluators now consider the most likely recovery from reservoirs will be the new "proved plus probable" reserves.

This evaluation has been prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The reserves definitions used in preparing this report (see Note 3 page 27)

are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101 (NI 51-101).

The results of the evaluations of GLJ, contained in the GLJ Report, based on both forecast and constant cost and price assumptions, are summarized in the following tables. The present worth of estimated future cash flows contained in the following tables may not be representative of the fair market values of the reserves. Assumptions relating to costs, prices for future production and other matters are summarized in the notes following the tables. There is no assurance that such prices and cost assumptions will be attained and variances could be material.

The Company's estimated proved Canadian reserves at January 1, 2004 were 1.1 million boe (January 1, 2003 – 1.6 million boe). The decrease of 31 percent is due to production of 0.3 million boe and dispositions of 0.5 million boe, partially offset by new discoveries of 0.2 million boe and positive revisions of 0.1 million boe.

The Company's estimated proved plus probable Canadian reserves at January 1, 2004 were 1.4 million boe (January 1, 2003 – 2.2 million boe). The decrease of 35 percent is attributable to production of 0.3 million boe and dispositions of 0.6 million, offset by new discoveries of 0.3 million boe. In addition, the new evaluation standards under the guidance of National Instrument 51-101, combined with negative revisions, resulted in a decrease of 0.2 million boe.

Reserve additions through successful drilling and well recompletions in 2003 replaced 96 percent of the year's production on a proved plus probable basis, and 59 percent on a proved basis.

The Company's total Canadian capital investment in 2003 was $5.5 million, of which $4.9 million was categorized as exploration and development expenditures for the purpose of finding oil and natural gas reserves. Production increases from the 2003 drilling program added 2 mmcf per day of natural gas, for an onstream cost of $14,715 per boe per day. Finding and development costs for 2003 were higher than expected at $13.34 per boe on a proved plus probable basis and $24.73 per boe on a proved basis only. The high F&D costs are the result of disappointing low volumes of gas reserves attributed to four new wells in the Pembina-Rat Creek area, two of which went on production in December 2003 with the remaining two wells on production in early 2004. Additional reserves may be allocated to these wells based on their production performance.

OIL, NATURAL GAS AND NGL RESERVES AND PRESENT WORTH VALUE OF ESTIMATED FUTURE CASH FLOWS
Based on Forecast Price and Cost Assumptions
Effective January 1, 2004

	Crude Oil (mstb)		Liquids (mstb)		Natural Gas (mmcf)		Barrel Equiv. (mboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved producing	140	125	84	64	4,709	3,933	1,009	844
Proved developed non-producing	–	–	–	–	45	36	7	6
Proved undeveloped	–	–	5	3	408	321	73	57
Total proved	140	125	89	67	5,162	4,290	1,089	907
Probable	32	29	17	13	1,667	1,428	327	280
Total proved plus probable	172	154	106	80	6,829	5,718	1,416	1,187

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE, FORECAST PRICES AND COSTS

As of January 1, 2004

	Before Income Taxes					After Income Taxes				
($ millions)	Discounted at (percent per year)					Discounted at (percent per year)				
Reserve Category[3]	0	5	10	15	20	0	5	10	15	20
Proved										
Developed producing	16.2	14.0	12.5	11.3	10.3	13.6	11.7	10.4	9.3	8.5
Developed										
Non-producing	–	–	–	–	–	–	–	–	–	–
Undeveloped	1.0	0.5	0.3	0.2	0.1	0.8	0.4	0.2	0.1	–
Total proved	17.2	14.5	12.8	11.5	10.4	14.4	12.1	10.6	9.4	8.5
Probable	4.2	3.1	2.4	1.9	1.6	2.7	1.9	1.4	1.2	1.0
Total proved plus probable	21.4	17.6	15.2	13.4	12.0	17.1	14.0	12.0	10.6	9.5

OIL, NATURAL GAS AND NGL RESERVES AND PRESENT WORTH VALUE OF ESTIMATED FUTURE CASH FLOWS

Based on Constant Price and Cost Assumptions

Effective January 1, 2004

	Crude Oil (mstb)		Liquids (mstb)		Natural Gas (mmcf)		Barrel Equiv. (mboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved producing	163	146	85	64	4,813	4,017	1,050	879
Proved developed non-producing	–	–	–	–	30	24	5	4
Proved undeveloped	–	–	5	3	407	321	73	57
Total proved	163	146	89	67	5,250	4,362	1,128	940
Probable	42	38	18	13	1,722	1,474	346	296
Total proved plus probable	205	184	107	80	6,972	5,836	1,474	1,236

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

Constant Prices and Costs

As of January 1, 2004

	Before Income Taxes					After Income Taxes				
($ millions)	Discounted at (percent per year)					Discounted at (percent per year)				
Reserve Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed producing	21.5	18.3	16.1	14.4	13.0	17.1	14.5	12.7	11.3	10.3
Developed										
Non-producing	0.1	–	–	–	–	–	–	–	–	–
Undeveloped	1.3	0.8	0.5	0.3	0.2	1.0	0.6	0.3	0.2	0.1
Total proved	22.9	19.1	16.6	14.7	13.2	18.1	15.1	13.0	11.5	10.4
Probable	6.2	4.6	3.5	2.8	2.4	4.0	2.8	2.2	1.7	1.4
Total proved plus probable	29.1	23.7	20.1	17.5	15.6	22.1	17.9	15.2	13.2	11.8

TOTAL FUTURE NET REVENUE (Undiscounted)
Forecast Prices and Costs
Effective January 1, 2004

($ millions) Reserve Category[3]	Revenue	Royalties	Operating Costs	Devel. Costs	Well Aband. Costs	Future Net Revenue Before Income Taxes	Income Costs	Future Net Revenue After Taxes
Proved reserves	33.7	4.7	11.2	0.6	–	17.2	2.8	14.4
Proved plus probable preserves	43.4	5.8	14.8	1.3	0.1	21.4	4.3	17.1

The estimate of future site restoration costs on existing wells at December 31, 2003 is $2.8 million. This value has not been included in the well abandonment costs in the preceding chart.

FUTURE NET REVENUE BY PRODUCTION GROUP
Forecast Prices and Costs
Effective January 1, 2004

Reserves Category	Production Group	Future Net Revenues Before Income Taxes (Discounted at 10 percent per year) ($000s)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	641
	Heavy oil (including solution gas and other by-products)	–
	Natural Gas (including by-products but excluding solution gas from oil wells)	12,132
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	735
	Heavy oil (including solution gas and other by-products)	–
	Natural Gas (including by-products but excluding solution gas from oil wells)	14,438

Notes:

(1) Gross reserves are defined as those reserves accruing to the Company's interest before deduction of interests and royalties owned by others, including Crown and freehold royalties.

(2) Net reserves are defined as those reserves accruing to the Company's interest after deduction of all interests and royalties owned by others, including Crown and freehold royalties.

(3) Definitions used for reserves categories in the GLJ Report are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI51-101) and in the COGE Handbook. They are as follows:

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Section 5.4.1 (GOGE Handbook) are applicable to individual Reserves Entities, which refers to the lowest level at which reserves calculations are performed, and to Reported Reserves, which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

> at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

> at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;

> at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically-derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilities or deterministic methods.

Incorporation of these guidelines means that corporate total proved reserves reflects a conservative estimate and proved plus probable reserves reflects a "best estimate" of the oil and gas quantities which will be recovered.

Documented Reserves Categories

Production and revenue projections are prepared for each of the following main reserves categories:

Reserves Category
Proved
Probable, and proved plus probable
Proved plus probable plus possible*

Production and Development Status
Developed producing **
Developed non-producing
Undeveloped
Total (sum of developed producing, developed non-producing and undeveloped)

*Generally, GLJ only evaluates possible reserves when specifically requested by a client.
**As producing reserves are inherently developed, GLJ simply refers to "developed producing" reserves as "producing."

When evaluating reserves, GLJ evaluators generally first identify the producing situation and assign proved, proved plus probable and proved plus probable plus possible reserves in recognition of the existing level of development and the existing depletion strategy. Incremental non-producing (developed non-producing or undeveloped) reserves are subsequently assigned recognizing future development opportunities and enhancements to the depletion mechanism. It should be recognized that future developments may result in accelerated recovery of producing reserves.

(4) GLJ has prepared its January 1, 2004 price and market forecasts as summarized on page 29 after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

Forecast Prices and Cost

As of January 1, 2004

Year	Crude Oil Edmonton References ($/bbl)[1]	Natural Gas AECO-C Spot ($/mcf)
Weighted Average		
Historical Price for 2003	43.51	6.66
2004	37.75	5.85
2005	33.75	5.15
2006	32.50	5.00
2007	32.50	5.00
2008	32.50	5.00
2009	32.50	5.00
2010	32.50	5.00
2011	32.50	5.00
2012	32.50	5.00
2013	32.50	5.00
2014	32.50	5.00
2015	+1.5 percent per year	+1.5 percent per year

Note: (1) 40 degrees API, 0.3 percent sulphur

(5) In the escalated pricing determination, operating and capital costs are assumed to increase at 1.5 percent per year.

(6) Under the constant price scenario, prices and costs are held constant for the life of the reserves. The crude oil at Edmonton price was held constant at Cdn$40.81 per barrel, and the natural gas AECO spot price was held constant at Cdn$6.09 per mmbtu.

(7) The U.S.$/Cdn.$ Exchange rate is assumed to be 0.75 in 2004 and thereafter.

(8) In the course of the January 1, 2004 evaluation, Eurogas provided GLJ personnel with basic information which included land data, well information, geological information, contract information, operating cost date, financial data and discussions of future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators, and from GLJ nonconfidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted as represented. The accuracy of any reserves and production estimates is a function of the quality and quantity of available data of engineering interpretation and judgement. While reserves and production estimates presented herein were considered reasonable at the time they were prepared, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. Revenue projections presented in the GLJ Report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized in the GLJ Report. Present values of revenues documented in the GLJ Report do not represent the fair market value of the reserves evaluated therein.

(9) Columns may not add due to rounding.

(10) The GLJ Report includes certain capital expenditures over 2004, 2005 and 2006 in order to achieve the predicted present worth values in the forecast price and constant price cases. There are no capital expenditures to be expended in 2004, 2005 and 2006 in both the escalating and constant price case.

(11) Royalty credits under the Alberta Royalty Tax Credit plan have not been included in this analysis of the individual property cash flows, but are included in the corporate consolidation level, where provided by the Company and as applicable, and have been adjusted with the Alberta gas cost allowance adjustments.

The following table provides a continuity of reserves from the January 1, 2003 reserve determination to the January 1, 2004 reserve determination:

	Crude Oil and Liquids (mstb)			Natural Gas (mmcf)			Barrel Equivalent (mboe)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening,									
January 1, 2003	694	240	934	5,427	2,382	7,809	1,599	637	2,236
Adjustment (1)	–	(15)	(15)	–	(775)	(775)	–	(144)	(144)
Revised opening	694	225	919	5,427	1,607	7,034	1,599	493	2,092
Development	2	1	3	983	608	1,591	166	103	268
Acquisitions	10	–	10	52	–	52	19	–	19
Dispositions	(452)	(157)	(609)	(110)	–	(110)	(470)	(157)	(627)
Production	(102)	–	(102)	(1,065)	–	(1,065)	(280)	–	(280)
Revisions	77	(20)	57	(125)	(548)	(673)	55	(112)	(56)
January 1, 2004	229	49	278	5,162	1,667	6,829	1,089	327	1,416

(1) The adjustment relates to the change in reserve definitions as defined under National Instrument 51-101. The adjustment has been applied to the opening balance for comparability purposes.

LIQUIDITY AND CAPITAL RESOURCES

The Company funded its capital expenditure program from cash flow from operations and existing cash and short-term deposits. The Company has a revolving credit facility of $4.5 million which bears interest at the bank's prime lending rate plus 0.375 percent. The facility is secured by the Company's Canadian oil and natural gas assets. At December 31, 2003 no amounts were drawn against the facility.

At December 31, 2003, the Company had a working capital surplus of $8.8 million. Included in working capital are cash and short-term deposits totalling $9.7 million. U.S. dollar-denominated cash and short-term deposits totalled $6.3 million (US$4.9 million), with the remaining $3.4 million held primarily in Canadian funds.

At December 31, 2003, the Company's market value of common shares was $50.1 million based on the closing price of $0.66 per share and 75,932,181 shares outstanding. During 2003 and 2002, Eurogas issued no new share capital except through the exercise of share options. The number of common shares outstanding at March 19, 2004 remains at 75,932,181.

The total International capital program for 2004 is US$12.9 million, with the 2004 Canadian program totalling $4.4 million. Although a significant portion of these budgeted expenditures are discretionary, the Company may be required to obtain external financing.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has an outstanding work commitment to drill one well with respect to the El Hamra exploration permit, which is located in south-central Tunisia.

Pursuant to the Company's office lease arrangements, the following payments are required over the remaining term of the lease:

2004	$160,500
2005	$160,500

RELATED PARTY TRANSACTIONS

During 2003 $150,000 (2002 – $150,000) was paid to a management corporation which remunerated the Chairman of the Company for his services.

BUSINESS RISKS

The Company is engaged in the exploration, development and production of crude oil and natural gas. The oil and natural gas industry is highly competitive. In addition, the Company is exposed to a number of risks including:

Commodity Pricing – Future revenues depend on benchmark prices for crude oil and natural gas, which fluctuate from time to time. Adverse fluctuations can have a significant negative effect on the Company's revenues. The Company has not entered into a commodity hedge program to protect its reinvestment potential as the strong balance sheet provides adequate protection from decline in commodity prices. This strategy also allows Eurogas to fully benefit in a high commodity-price environment.

Exploration Risks – Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that additional oil or natural gas reserves in commercial quantities will be discovered by the Company. Eurogas mitigates these risks by employing experienced and qualified people and using sound business practices. The Company follows all government regulations, and has an up-to-date emergency response plan. Property and liability insurance in place provides a reasonable amount of protection from risk of loss.

Political Risks – The Company's operations are subject to business risks inherent in the oil and natural gas industry. These risks can involve matters arising out of government policies, imposition of special taxes or similar charges by government bodies, foreign exchange fluctuations and controls, access to capital markets, civil disturbances, deprivation or unenforceability of contract rights or the taking of property without fair compensation.

CRITICAL ACCOUNTING ESTIMATES

Oil and Gas Properties

The Company follows the full-cost method of accounting for exploration and development expenditures whereby all costs related to the exploration for and development of oil and natural gas reserves are accumulated in separate country-by-country cost centres. Costs include lease acquisition, geological and geophysical expenditures, carrying costs of non-productive properties, the drilling of productive and non-productive wells and related plant and production equipment costs, and that portion of general and administrative expenses and interest directly attributable to exploration and development activities.

The Company has three cost centres – Canada, Tunisia and Spain. All of the Company's production and reserves are associated with the Canadian cost centre.

The Company is currently in the exploratory stage of a drilling program in Tunisia and capitalizes all costs. The recovery of the recorded costs is contingent upon the existence of economically recoverable reserves, and future profitable production.

Activities in Spain are in the pre-development phase. All pre-development costs relating to the Castor exploration permit in Spain are capitalized. The recovery of these costs is dependent upon the economic viability of the underground gas storage project.

The Company calculates a "cost ceiling" which limits the net book value of its Canadian capital costs to the undiscounted and unescalated estimated future net revenues from production of proved reserves based upon period-end prices, plus the cost of unproved properties, less any impairment, after deduction of future development costs, general and administrative expenses, site restoration and abandonment costs, financing costs and income taxes. Additional depletion is provided if the net book value of capitalized costs exceeds such future revenue. The commodity prices used for the purposes of the December 31, 2003 ceiling test were $5.94 per mcf for natural gas and $36.33 per barrel for oil and natural gas liquids. These prices approximate the prices received by the Company for December 2003 sales.

Depletion and depreciation of Canadian oil and natural gas properties and equipment is computed using the unit-of-production method where the ratio of production to proved reserves, before royalties, determines the proportion of depletable costs to be expensed. The cost of undeveloped properties at December 31, 2003 totalled $1.1 million and was excluded from the depletion calculation. Such costs are excluded until quantities of proved reserves are found or impairment occurs. Volumes are converted to equivalent units using the ratio of one barrel of oil to six mcf of natural gas. Future development costs totalling $0.6 million were included in the depletion and ceiling test calculation.

Site Restoration and Abandonment Cost

The Company annually evaluates costs of future well abandonment and site restoration for its properties. The estimated costs are provided for by the unit-of-production method. The Company provides for site restoration and

abandonment for all wells and facilities that it has an interest in, and bases its estimate on historical costs incurred at similar sites and anticipated costs based on industry knowledge. Actual costs of well abandonment and site restoration are charged to the accumulated provision when incurred.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of oil and natural gas properties, the provision for future site restoration and abandonment costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Per Share Information

Basic earnings per common share are computed by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding during the period (2003 – 75,770,332; 2002 – 75,616,428). Diluted earnings per common share are calculated using the treasury stock method to determine the dilutive effect of stock options. The treasury stock method assumes that the proceeds received from the exercise of "in the money" stock options are used to repurchase common shares at the average market price during the year. The diluted weighted average common shares for 2003 are 77,141,981 (2202 – 76,523,256).

NEW ACCOUNTING PRONOUNCEMENTS

Stock-Based Compensation

In 2003, and in accordance with recently released Canadian Institute of Chartered Accountants (CICA) guidance for stock-based compensation, the Company elected to recognize compensation expense using the fair value method on a prospective basis when stock options with no cash settlement features are granted to employees and directors under the fixed share option plan. Under this method, compensation expense is measured at the grant date and recognized as a charge to earnings over the vesting period with a corresponding credit to contributed surplus. The fair value of the options is determined using the Black-Scholes option pricing model. Prior to 2003 the Company reported the impact of recognizing the fair value of options granted to employees and directors on a pro forma basis in the notes to the Company's financial statements.

Asset Retirement Obligations

The CICA recently issued Handbook Section 3110-Asset Retirement Obligations. The recommendation is effective for fiscal years beginning on or after January 1, 2004 and requires liability recognition for retirement obligations associated with the Company's oil and natural gas properties. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the Company expects to settle the retirement obligation. The total impact on the Company's financial statements has not yet been determined.

Hedging Relationships – Accounting Guideline AcG -13

In December 2001, the CICA issued AcG-13 which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The Guideline is effective

for fiscal years beginning on or after July 1, 2003. The Company anticipates that adoption of AcG-13 will not have a material impact on its financial statements.

Full Cost Accounting in the Oil and Gas Industry – Accounting Guideline AcG-16

In September 2003, the CICA issued Accounting Guideline AcG-16, Oil and Gas Accounting – Full Cost which replaces AcG-5 Full Cost Accounting in the oil and gas industry. The main features of AcG-16 are as follows:

> Reserve definitions have been made consistent with those in the Society of Petroleum Evaluation Engineers Handbook. These definitions are also utilized in the Canadian Securities Administrators' National Instrument 51-101.

> The impairment of a cost centre is recognized when its carrying amount is greater than its undiscounted future cash flows. In the recognition step, only proved reserves are allowed, and the prices used in estimating future cash flows should be based on the best information available to the enterprise. This would normally be consistent with quoted benchmark prices in the futures market, or based on reputable industry forecasts.

> If impairment is recognized, the amount of impairment is determined as the excess of the carrying amount over the fair value. Fair value is based on the present value of expected cash flows, reflecting discounting at the risk-free rate of interest. Both proved and some portion of probable reserves are also used in estimating fair value.

AcG-16 is applicable to fiscal years beginning on or after January 1, 2004. The cumulative amount that would have been recognized in prior years had this section been applied, less any amount previously recognized, should be recognized as the effect of a change in accounting policy and charged to opening retained earnings for the fiscal year in which this section is initially applied, without restatement of prior periods. The total impact on the Company's financial statements has not yet been determined.

2003 QUARTERLY INFORMATION

	Q1	Q2	Q3	Q4	Annual
Financial					
Oil and gas sales, net of royalties	**$ 2,547,434**	**$ 2,027,983**	**$ 2,046,863**	**$ 2,156,830**	**$ 8,779,110**
Cash flow from operations	**1,888,907**	**1,024,949**	**1,044,223**	**1,498,232**	**5,456,311**
basic and diluted	**0.03**	**0.01**	**0.01**	**0.02**	**0.07**
Net earnings (loss)	**537,319**	**(240,502)**	**245,459**	**30,294**	**572,570**
basic and diluted	**0.01**	**0.00**	**0.00**	**0.00**	**0.01**
Capital expenditures	**2,016,640**	**1,784,651**	**3,142,765**	**2,931,739**	**9,875,795**
Operating					
Average daily production					
Oil and liquids (bbls/d)	**310**	**298**	**319**	**193**	**280**
Natural gas (mcf/d)	**2,661**	**2,670**	**2,880**	**3,446**	**2,919**
BOE equivalent (6:1)	**754**	**743**	**800**	**768**	**767**
Average prices					
Oil and liquids ($/bbl)	**41.93**	**33.87**	**33.68**	**35.85**	**36.36**
Natural gas ($/mcf)	**8.16**	**6.55**	**6.28**	**5.87**	**6.64**

2002 QUARTERLY INFORMATION

	Q1	Q2	Q3	Q4	Annual
Financial					
Oil and gas sales, net of royalties	$ 1,383,384	$ 1,965,352	$ 1,327,003	$ 2,054,356	$ 6,730,095
Cash flow from operations	693,031	1,095,682	402,017	1,307,575	3,498,305
basic and diluted	0.01	0.01	0.01	0.02	0.05
Net earnings (loss)	249,113	284,014	(257,397)	4,444,391	4,720,121
basic and diluted	0.00	0.00	0.00	0.06	0.06
Capital expenditures	1,662,430	1,174,155	2,057,930	1,366,139	6,260,654
Operating					
Average daily production					
Oil and liquids (bbls/d)	361	347	316	319	337
Natural gas (mcf/d)	2,856	2,923	2,880	2,717	2,841
BOE equivalent (6:1)	837	834	796	773	811
Average prices					
Oil and liquids ($/bbl)	24.45	33.92	30.75	36.36	32.15
Natural gas ($/mcf)	3.26	4.15	3.19	5.66	4.17

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements, the notes thereto and other financial information contained in this annual report have been prepared by, and are the responsibility of, the management of Eurogas Corporation. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, using management's best estimates and judgements when appropriate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee, which is comprised of directors, none of whom are employees of the Company, meets with management as well as the external auditors to satisfy itself that management is properly discharging its financial reporting responsibilities and to review its consolidated financial statements and the report of the auditors. It reports its findings to the Board of Directors who approve the consolidated financial statements.

The consolidated financial statements have been audited by Ernst & Young LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards. The auditors have full and unrestricted access to the Audit Committee.

Julio Poscente
Chairman of the Board and Chief Executive Officer
March 19, 2004

Stuart Jaggard
Controller

Auditors' Report

To the Shareholders of Eurogas Corporation:

We have audited the consolidated balance sheets of Eurogas Corporation as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

Calgary, Alberta
March 19, 2004

Consolidated Balance Sheets

DECEMBER 31	**2003**	2002
ASSETS		
Current		
Cash and short-term deposits	**$ 9,671,024**	$ 8,532,799
Accounts receivable, prepaids and other	**2,204,916**	2,636,089
Natural gas inventory (Note 2)	**–**	1,513,521
	11,875,940	12,682,409
Notes receivable (Note 3)	**1,019,938**	963,509
Oil and gas properties (Note 4)	**33,997,548**	29,438,153
Future income taxes (Note 9)	**1,249,731**	2,307,731
	$ 48,143,157	$ 45,391,802
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 3,044,376**	1,097,590
Bank debt (Note 8)	**–**	539,000
	3,044,376	1,636,590
Provision for site restoration	**893,339**	439,894
Non-controlling interest	**1,802,000**	1,579,000
	5,739,715	3,655,484
SHAREHOLDERS' EQUITY		
Share capital (Note 6)	**35,434,728**	35,350,728
Contributed surplus (Note 7)	**10,554**	–
Retained earnings	**6,958,160**	6,385,590
	42,403,442	41,736,318
Commitments (Note 10)		
	$ 48,143,157	$ 45,391,802

See accompanying notes.

On behalf of the board

Derek H.L. Buntain

Derek H.L. Buntain, Director

Garth A.C. MacRae, Director

Consolidated Statements of Operations and Retained Earnings

YEARS ENDED DECEMBER 31	2003	2002
REVENUE		
Oil and gas sales, net of royalties	**$ 8,779,110**	$ 6,730,095
Natural gas marketing revenue (Note 2)	**2,580,771**	1,479,727
Interest and other	**157,719**	154,601
	11,517,600	8,364,423
EXPENSES		
Operating	**2,017,629**	2,036,968
Natural gas purchases (Note 2)	**2,434,497**	1,313,363
General and administrative	**1,464,135**	1,366,743
Interest	**33,274**	44,278
Depreciation, depletion and site restoration	**2,234,094**	1,893,000
	8,183,629	6,654,352
EARNINGS BEFORE THE UNDERNOTED	**3,333,971**	1,710,071
Unrealized exchange loss	**(1,391,397)**	–
(Charge) recovery of amounts written-off related to Urengoil Inc. (Note 4(d))	**(200,250)**	4,652,816
EARNINGS BEFORE TAXES	**1,742,324**	6,362,887
PROVISION FOR TAXES (NOTE 9)	**1,169,754**	1,642,766
NET EARNINGS	**572,570**	4,720,121
RETAINED EARNINGS, BEGINNING OF THE YEAR	**6,385,590**	1,665,469
RETAINED EARNINGS, END OF THE YEAR	**$ 6,958,160**	$ 6,385,590
EARNINGS PER COMMON SHARE Basic and diluted (Note 1)	**$ 0.01**	$ 0.06

See accompanying notes.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31	2003	2002
OPERATING ACTIVITIES		
Net earnings	**$ 572,570**	$ 4,720,121
Depreciation, depletion and site restoration	**2,234,094**	1,893,000
Provision for future income taxes	**1,058,000**	1,538,000
Unrealized exchange loss	**1,391,397**	–
Charge (recovery of amounts written-off) related to Urengoil Inc.	**200,250**	(4,652,816)
Cash flow from operations	**5,456,311**	3,498,305
Changes in non-cash working capital balances	**3,902,034**	(2,972,320)
Cash provided by operating activities	**9,358,345**	525,985
FINANCING ACTIVITIES		
Issue of share capital	**84,000**	45,000
Proceeds on issuance of Partnership units (Note 4(b))	**285,105**	–
Acquisition of interest in Partnership (Note 4(b))	**–**	(1,494,483)
Repayment of bank debt	**(539,000)**	–
Change in non-cash working capital	**(56,429)**	(23,035)
Cash used in financing activities	**(226,324)**	(1,472,518)
INVESTING ACTIVITIES		
Disposition of oil and gas properties (Notes 4(a &d))	**3,387,951**	4,652,816
Investment in oil and gas properties (Note 4)	**(9,875,795)**	(6,260,654)
Abandonment and site restoration	**(114,555)**	(257,478)
Cash used in investing activities	**(6,602,399)**	(1,865,316)
Foreign exchange loss on cash held in foreign currency	**(1,391,397)**	–
INCREASE (DECREASE) IN CASH AND SHORT-TERM DEPOSITS	**1,138,225**	(2,811,849)
CASH AND SHORT-TERM DEPOSITS, BEGINNING OF THE YEAR	**8,532,799**	11,344,648
CASH AND SHORT-TERM DEPOSITS, END OF THE YEAR	**$ 9,671,024**	$ 8,532,799

See accompanying notes.

YEARS ENDED DECEMBER 31, 2003 AND 2002

1. SIGNIFICANT ACCOUNTING POLICIES

Eurogas Corporation (the "Company") is an oil and gas company which carries on exploration, development, production and/or acquisition activities in Canada, Spain and Tunisia. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and reflect the following policies:

Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries.

Foreign Currency Translation

The Company follows the temporal method in accounting for its integrated foreign operations and translates its foreign-denominated monetary assets and liabilities at the exchange rate prevailing at year-end. Non-monetary assets and liabilities are translated at historic rates. Revenues and expenses are translated at the average rate of exchange for the year. Exchange gains or loss are included in operations.

Financial Instruments

The Company's financial instruments at December 31, 2003 consist of cash and short-term deposits, accounts receivable, notes receivable and accounts payable and accrued liabilities. At December 31, 2003 the fair value of financial instruments approximated book value due to the near term maturity or the associated interest rate terms.

The Company has entered into commodity price derivative instruments to reduce the exposure of adverse fluctuations in commodity prices on the value of gas inventory. No contracts are entered into for trading or speculative purposes. Gains and losses relating to commodity price derivative instruments that meet hedge criteria are recognized as part of natural gas marketing revenue concurrently with the hedged transaction.

The Company's policy is to formally designate each commodity price derivative instrument as a hedge of a specifically identified future revenue stream. The Company believes the commodity price derivative instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount and the commodity price basis in the instruments all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with commodity price derivative instruments, which have been terminated or cease to be effective prior to maturity, are deferred as other current or non-current assets or liabilities on the balance sheet as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related commodity price derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

Natural Gas Inventory

Natural gas inventory is carried at the weighted average cost, subject to any lower of cost and market adjustments.

Exploration and Development Expenditures

The Company follows the full cost method of accounting for exploration and development expenditures whereby all costs related to the exploration for and development of oil and gas reserves are accumulated in separate country-by-country cost centres. Costs include lease acquisition, geological and geophysical expenditures, carrying costs of non-productive properties, the drilling of productive and non-productive wells and related plant and production equipment costs, and that portion of general and administrative expenses and interest

directly attributable to exploration and development activities. Proceeds received from the disposal of properties are normally deducted from the full cost pool without recognition of a gain or loss. When a significant portion of properties is sold a gain or loss is recorded and reflected in the statement of operations.

The Company is currently in the exploratory stage of a drilling program in Tunisia and capitalizes all costs. The recovery of the recorded costs is contingent upon the existence of economically recoverable reserves, and future profitable production.

Recovery of Capitalized Costs

The Company calculates a “cost ceiling” which limits the net book value of capital costs to the undiscounted and unescalated estimated future net revenues from production of proved reserves based upon period end prices, plus the cost of unproved properties, less any impairment, after deduction of future development costs, general and administrative expenses, site restoration and abandonment costs, financing costs and income taxes. Additional depletion is provided if the net book value of capitalized costs exceeds such future revenue.

Joint Ventures

Substantially all of the Company’s exploration, development and production activities are conducted jointly with other entities and accordingly the accounts reflect only the Company’s proportionate interest in such activities.

Pre-development Costs

All pre-development costs relating to the Castor permit in Spain are capitalized. The recovery of these costs is dependent upon the economic viability of the project.

Revenue Recognition

Oil and natural gas sales are recognized when commodities are sold.

Depletion and Depreciation

Depletion and depreciation of oil and gas properties and equipment is computed using the unit-of-production method where the ratio of production to proved reserves, before royalties, determines the proportion of depletable costs to be expensed. Undeveloped properties are excluded from the depletion calculation until quantities of proved reserves are found or impairment occurs. Volumes are converted to equivalent units using the ratio of one barrel of oil to six mcf of natural gas. Depreciation of office equipment and computer equipment is provided for on a 10 percent and 35 percent straight-line basis respectively.

Site Restoration and Abandonment Costs

The Company annually evaluates costs of future well abandonment and site restoration for its properties. The estimated costs are provided for by the unit-of-production method and are included in depletion and depreciation expense. Actual costs of well abandonment and site restoration are charged to the accumulated provision when incurred.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties and the provision for future site restoration and abandonment costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Stock-based Compensation

In 2003, and in accordance with recently released Canadian Institute of Chartered Accountants (CICA) guidance for stock-based compensation, the Company elected to recognize compensation expense using the fair value method on a prospective basis when stock options with no cash settlement features are granted to employees and directors under the fixed share option plan. Under this method, compensation expense is measured at the grant date and recognized as a charge to earnings over the vesting period with a corresponding credit to contributed surplus. The fair value of the options is determined using the Black-Scholes option pricing model. Prior to 2003 the Company reported the impact of recognizing the fair value of options granted to employees and directors on a pro forma basis in the notes to the Company's financial statements.

Income Taxes

The Company currently earns revenue only in Canada and is not in a taxable position as available tax deductions are in excess of the related book values. All international projects are in the pre-production stage of development and capitalized costs to date will be available for deduction for income tax purposes in the respective jurisdictions, once commercial operations commence.

The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded as if all assets and liabilities on the balance sheet were settled at their carrying amounts at the substantively enacted income tax rates at the balance sheet date.

Cash and Cash Equivalents

Cash and cash equivalents are cash and short-term deposits with a maturation of a short-term nature, less than 90 days. The interest rate earned on the short-term deposits varies from 0.4 percent to 1.0 percent.

Per Share Information

Basic earnings per common share are computed by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding during the period (2003 – 75,770,332; 2002 – 75,616,428). Diluted earnings per common share are calculated using the treasury stock method to determine the dilutive effect of stock options. The treasury stock method assumes that the proceeds received from the exercise of "in the money" stock options are used to repurchase common shares at the average market price during the year. The diluted weighted average common shares for 2003 are 77,141,981 (2002 – 76,523,256).

2. NATURAL GAS INVENTORY

During 2002 the Company purchased natural gas and immediately entered into binding contracts to sell the natural gas to various industry purchasers. The gas was stored in the Cantuar gas storage facility in Saskatchewan and was delivered during 2002 and 2003. At December 31, 2003, the Company has fulfilled all of its delivery commitments.

3. NOTES RECEIVABLE

During 2002, the Company advanced funds aggregating $940,474 to certain unit holders of the Castor UGS Limited Partnership (see Note 4(b)). The advances bear interest at 6 percent per annum, are secured by promissory notes and the respective partnership interests, and are repayable by August 1, 2012. Accrued interest of $79,464 has been included in the balance as at December 31, 2003 (2002 – $23,035). The fair value of the Notes approximate the carrying value as reported on the balance sheet.

4. OIL AND GAS PROPERTIES

Following are the oil and gas properties by cost centre:

	2003	2002
Canada	**$ 8,655,166**	$ 8,217,029
Spain	**8,498,975**	6,854,334
Tunisia	**16,843,407**	14,366,790
	$ 33,997,548	$ 29,438,153

The capital investment during the year by cost centre was as follows:

	2003	2002
Canada	**$ 5,508,791**	$ 1,895,217
Spain	**1,994,048**	1,399,650
Tunisia	**2,372,956**	2,965,787
	$ 9,875,795	$ 6,260,654

a) Canada

The net book value for Canadian oil and gas properties of $8,655,166 at December 31, 2003 (2002 – $8,217,029) is after deducting accumulated depreciation and depletion of $26,853,774 (2002 – $25,265,139).

At December 31, 2003, oil and gas properties include $1,094,487 (2002 – $875,340) relating to unproved properties which have been excluded from the depletion and ceiling test calculations. Future development costs relating to proved undeveloped reserves of $573,000 (2002 – $861,000) are included in the depletion and ceiling test calculations.

The Company has capitalized as part of its Canadian oil and gas properties $295,360 of general and administrative expenses (2002 – $284,769).

Effective July 1, 2003 the Company sold its interests in the East Cantuar area for cash consideration, net of adjustments, of $2,270,371. The Company's commitment at the end of December 31, 2002 to purchase 665,000 GJ of natural gas remaining in the gas cap at the East Cantuar Gas Unit was extinguished with the sale. The sale closed on September 24, 2003, with the Company recording the results of operations of its interests for the period up to September 24, 2003.

Effective November 1, 2003 the Company sold its interest in the Ingoldsby area for cash consideration, net of adjustments, of $1,337,625. The sale closed on November 21, 2003, with the Company recording the results of operations of its interest in the property for the period up to November 21, 2003.

b) Spain

The Company holds a majority interest in the Castor exploration permit through Castor UGS Limited Partnership, which was formed in 2001. The Castor Exploration permit covers the abandoned Amposta oilfield, which is suitable for development as a natural gas storage facility. During 2002, in connection with the acquisition of Partnership units from existing unit holders, the Company's interest in the Partnership increased to 73 percent.

In January 2003 an additional 170,722 units in the Castor UGS Limited Partnership were issued by the Partnership to new unit holders for cash consideration of $285,105. The issuance reduced the Company's interest in the Partnership from 73 percent to 71 percent. All the expenditures to date relate to pre-development costs.

c) Tunisia

In 2001, the Company entered into an agreement with another company ("Participant") whereby the Participant agreed to fund US$5.2 million of the costs of an exploration drilling program. Subsequent to December 31, 2003 the balance remaining of US$910,000 was owing, and was received by the Company in January 2004, fulfilling the Participant's funding obligation. The amount received will be credited to the Tunisian full cost pool.

In 2003, the Company relinquished its interest in the Jorf permit. The Company retains a 50 percent interest in the Bazma and El Hamra permits.

The Company, along with a joint-venture partner, was awarded the 908,000 acre Sfax permit located offshore in Tunisia's Gulf of Gabes. The Company maintains a 45 percent interest in the permit.

d) Russia

During 2002, the Company received additional proceeds of $4,652,816 (US$3,000,000) in connection with the sale all of its shares in Yamalo, a wholly-owned subsidiary which held a 50 percent interest in Urengoil, a Russian joint stock company. This recovery is reflected as income in 2002 and had no associated tax impact. Subsequent to December 31, 2003, the Company paid outstanding commissions of $200,250 (US$150,000) relating to this sale. The amount has been accrued in the December 31, 2003 consolidated statement of operations.

5. SEGMENTED INFORMATION

All activities of the Company are in petroleum and natural gas exploration and development with all operating revenues to date earned in Canada. The total identifiable assets by geographic area are as follows:

	2003	2002
Canada	**$ 22,348,466**	$ 23,502,489
Spain	**8,951,284**	7,522,523
Tunisia	**16,843,407**	14,366,790
	$ 48,143,157	$ 45,391,802

6. SHARE CAPITAL

	Number of Shares	Amount
Authorized:		
An unlimited number of common and first preference shares, issuable in series		
Issued and fully paid:		
Common shares, December 31, 2001	75,532,181	$ 35,305,728
Exercise of share options	150,000	45,000
Common shares, December 31, 2002	75,682,181	35,350,728
Exercise of share options	250,000	84,000
Common shares, December 31, 2003	**75,932,181**	**$ 35,434,728**

On May 30, 1997 the shareholders of the Company approved an arrangement whereby the Chairman and Chief Executive Officer of the Company purchased 1,000,000 common shares of the Company at a price of $1.00 per share. The Company agreed to provide this officer with a loan of $1,000,000 to finance the purchase. The loan is non-interest bearing, is secured by a pledge of the 1,000,000 common shares and is repayable out of the proceeds of any sale of the common shares. The loan has been deducted from share capital.

7. SHARE OPTION PLAN

The Company has established a share option plan under which directors, officers, employees and consultants can be granted options to purchase common shares of the Company. The number of shares issuable under the plan cannot exceed 7,500,000 in total, and the number of shares issuable to any one person under the plan cannot exceed 5 percent of the total number of common shares outstanding from time to time. The exercise price of each option equals the market price of the Company's stock on the date of the grant and the option's term ranges from five to ten years.

A summary of the status of the share option plan is as follows:

		2003		2002
	Shares	**Weighted-Average Exercise Price**	Shares	Weighted-Average Exercise Price
Opening	**5,300,000**	**$0.41**	4,200,000	$0.49
Granted	**100,000**	**0.57**	1,450,000	0.38
Exercised	**(250,000)**	**(0.34)**	(150,000)	(0.30)
Cancelled	**(75,000)**	**(0.38)**	(200,000)	(2.01)
	5,075,000	**$0.41**	5,300,000	$0.41

At December 31, 2003 options to purchase 4,458,333 common shares (2002 – 4,150,000) were exercisable as follows:

Price $	Exercise Outstanding	Number of Shares Exercisable	Contractual Life (Years)
0.30	1,550,000	1,550,000	0.8
0.37	50,000	50,000	1.4
0.38	1,325,000	775,000	3.5
0.40	1,650,000	1,650,000	2.2
0.57	100,000	33,333	4.2
0.71	150,000	150,000	2.7
1.00	200,000	200,000	1.7
1.81	50,000	50,000	2.2
	5,075,000	4,458,333	

Total compensation expense is recognized over the vesting period of the option. Compensation expense of $10,554 has been recognized in 2003 (2002 – NIL) based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation.

The following table provides pro forma measures of 2002 net earnings, had compensation expense been recognized based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation.

	Year ended December 31, 2002
Reported net earnings	4,720,121
Compensation expense	52,329
Pro forma, net earnings	4,667,792

The estimated fair value of share options issued during the year was determined using the Black-Scholes model using the following weighted average assumptions:

	2003	2002
Risk-free interest rate	**4.5%**	5.0%
Expected hold period to exercise	**5 years**	5 years
Volatility in the price of the Company's shares	**76.4%**	74.2%
Dividend yield	**0%**	0%

8. BANK DEBT

The Company has a revolving credit facility of $4,500,000 with a Canadian chartered bank, which bears interest at the bank's prime lending rate plus 3/8 percent and has a standby fee of 0.25 percent per annum on undrawn amounts. Borrowings under this facility are secured by a demand debenture in the amount of $20,000,000, with a first floating charge on the Company's Canadian assets. The bank debt outstanding at December 31, 2002 was repaid in full in January 2003.

Interest expense and related standby fees related to the bank loan totalled $20,281 in 2003 (2002 – $39,682). Cash interest paid during the years ended December 31, 2003 and 2002 approximates interest expense in each year.

9. INCOME TAXES

The Company's future Canadian income tax assets are as follows:

	2003	2002
Temporary differences related to:		
Oil and gas properties	**$ 886,857**	$ 1,576,391
Non-capital loss carry-forwards	**–**	546,145
Abandonment and site restoration	**362,874**	185,195
	$ 1,249,731	$ 2,307,731

At December 31, 2003 the Company has exploration and development costs and undepreciated capital costs available for deduction against future taxable income of approximately $9,600,000.

The provision for income taxes differs from the amount computed by applying the combined Canadian federal and provincial tax rate of 40.62 percent (2002 rate of 42.12 percent) to the earnings before taxes of $1,742,324 in 2003 (2002 – $6,362,887). The difference results from the following:

	2003	2002
Computed expected provision for taxes	**$ 707,732**	$ 2,680,048
Effect on taxes of:		
International operations	**81,342**	(1,959,766)
Non-deductible Crown royalties, net of ARTC	**554,102**	549,875
Resource allowance	**(532,622)**	(366,994)
Other differences	**2,671**	(25,350)
Reduction in tax pool balances due to reassessments	**175,155**	631,800
Resource rate adjustments	**59,702**	–
Rate adjustment	**9,918**	28,387
Future taxes	**1,058,000**	1,538,000
Capital taxes	**111,754**	104,766
Provision for taxes	**$ 1,169,754**	$ 1,642,766

The Company currently earns revenue only in Canada. The adjustments for international operations are related to the charge (recovery of amounts written-off) related to Urengoil Inc. These adjustments are not taxable in Canada (see Note 4).

Cash taxes paid during the years ended December 31, 2003 and 2002 approximates capital tax expense in each year.

10. COMMITMENTS

Tunisia

During 2002 the El Hamra prospecting permit was converted to an exploration permit with a primary term of four years. The Company has an outstanding work commitment to drill one well with respect to the El Hamra exploration permit, which is located in south central Tunisia.

Canada

Pursuant to the Company's office lease arrangements, the following payments are required over the remaining term of the lease:

2004	$160,500
2005	$160,500

11. RELATED PARTY TRANSACTIONS

During 2003 $150,000 (2002 – $150,000) was paid to a management corporation which remunerated the Chairman of the Company for his services.

At December 31, 2002, the management corporation owed $58,425 to the Company for joint-venture billings on wells in which it was a partner (2003 – NIL).

12. REORGANIZATION

During 2003 the Board of Directors of the Company approved a plan to reorganize the Company by the separation of the Canadian assets and operations and the foreign assets and operations into two separate public Companies. The reorganization is subject to the approval of the shareholders of the Company and relevant regulatory bodies.

13. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

14. SUBSEQUENT EVENT

Subsequent to December 31, 2003 the Company settled a claim by a third party in respect of an overriding royalty arrangement that was outstanding at December 31, 2002. The settlement amount of $123,226 has been provided for in the December 31, 2003 financial statements as a charge to general and administrative expense.

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& Chief Executive Officer
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Ned Goodman (2)
Vice Chairman of the Board
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Jonathan Goodman
Toronto, Canada

Garth A.C. MacRae (1) (2)
Toronto, Canada

Derek H.L. Buntain (1)
Hamilton, Bermuda

R. James Kirker
Calgary, Canada

M. Jaffar Khan (1)
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(1) Audit Committee
(2) Compensation Committee

Officers

Julio Poscente
Chairman of the Board
& Chief Executive Officer

Jim Batchelor
Vice President, Exploration

Bruce W. Sherley
President & Chief Operating Officer

Donald R. Leitch
Corporate Secretary

Stuart W. Jaggard
Controller

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Designed and produced by Merlin Edge Inc.
Printed in Canada

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